

**THE “SUPPLY OF STORAGE”
FOR NATURAL GAS IN CALIFORNIA**

Rocío Uría

Department of Agricultural and Resource Economics, UC Davis.

1. INTRODUCTION

Futures markets provide intertemporal price signals. As Working (1934) first showed for wheat and others have observed for many other commodities, at least some, if not most, market participants pay attention to those intertemporal price signals.¹ Those holding stocks of wheat look to the nearby spread, holding considerably more stocks when the nearby spread is in contango than when it is in backwardation. Those holding commercial stocks in Chicago are extremely sensitive to the spreads in wheat futures prices at the Chicago Board of Trade, commercial holders outside the delivery area less sensitive, and farmers retaining wheat on farm least sensitive. Working (1948 and 1949) called the aggregate relationship a “supply-of-storage” curve.

The question remains open whether those not closely tuned to the intertemporal signals in a futures market are experiencing another signal or are simply inattentive. Even while wheat is temporarily scarce in Chicago and the futures spread in sharp backwardation, wheat could be abundant in a relatively isolated location and hence the effective local spot-forward spread be one of contango and an inducement for both commercial firms and farmers in that location to store (Williams and Wright, 1989). Or farmers could have planned to use their relatively small quantities of wheat as feed later in the year regardless of the spread at the time of their decision, let alone the subsequent day-to-day fluctuations in that price signal.

Daily data from April 2001 to September 2004 for natural gas stocks and flows into and out of storage within California allow a determination of the reach of futures prices. Although not efficient in pricing in its first years (Herbert, 1992), the NYMEX

¹ For eggs and butter (Brennan, 1958), for cotton and wheat (Telser, 1958), for coffee and cocoa (Thompson, 1986), for fuel oil (Lowry, 1988), for copper (Larson, 1994) and (Thurman, 1988).

natural gas futures market is now deep and active. Yet California is far from and only indirectly connected to the pipeline system centered on the Henry Hub in Louisiana, the delivery location on the NYMEX futures contract. Brinkmann and Rabinovitch (1995) earlier concluded that those in California would find limited hedging effectiveness to NYMEX futures. Two of the four storage facilities within California are operated by the two main distribution utilities, which are not organized as nimble trading firms and which are constrained by regulators to have a set quantity in store each November 1, the supposed start of the heating season. The other two facilities are operated primarily as a “public” grain elevator would be - charging a set price for storage for a set time - which has enticed a wide range of customers, some of whom are purely traders and who might be closely tuned to NYMEX futures spreads.

2. CHARACTERISTICS OF NATURAL GAS STORAGE

Apart from California’s remote location relative to the delivery point for the NYMEX futures contract and of the public utility character of the two biggest storage facilities, a third reason exists for making this an interesting study of the relationship between futures spreads and stocks: logistic and operational differences in storing natural gas compared to bulk commodities such as wheat, cotton, cocoa, and coffee.

Unlike grain, for which discontinuous supply is the main source of seasonality in stocks, natural gas inventories display a strong seasonal pattern originating on the demand side. So strong is this seasonality that there are two official seasons in natural gas storage, one for injection that runs April through October and one for withdrawals going November through March, delimited by the assumed length of residential heating

demand. When the relevant price spreads are in significant contango, a switch from drawdown to accumulation of inventories is possible for both grain and natural gas. For natural gas, one such adjustment is through the extraction rates at producing wells, just as for wheat through farmers releasing their on-farm stocks and providing them to a country grain elevator.

Natural gas flowing into and out of storage facilities competes for pipeline space with flows for other immediate uses. Injection or withdrawal displays a weekly cycle that peaks during the weekend, when other demand requirements are lower. For grain, however, provided the elevators are open, no obvious reason exists for receipts differing across days of the week.

Although grain elevators can be placed virtually anywhere, natural gas can be stored only underground, in depleted reservoirs, aquifers, or salt caverns; the geological characteristics of the formation partly determine how flexibly the facility can be operated. An added complication is that the facility needs to be connected to the pipeline network, and local congestion can be much more an issue than for grain storage. As for the costs of injecting storage into a facility, compressors use natural gas itself as fuel to push the flow into the reservoir. There is no analogue for such a physical cost when storing grain.² On the other hand, the operational complexities associated with different grades in grain storage do not exist for a homogeneous commodity like natural gas. The amounts of gas that can be put in and out of a facility are limited by the corresponding injection and withdrawal maximum rates or by the capacity in the connecting pipeline, whichever is

² Unlike grain bins, which can be emptied, natural gas storage facilities often need some minimum quantity present to keep the geological formation intact. This physical reality is recognized in the concept of “working gas”, which is the relevant storage amount from a marketing perspective.

less.³ Although such loading and unloading constraints do affect grain storage (Brennan, 1994), they seem less of an issue for a grain elevator, because the supply of transportation services can be considered nearly perfectly elastic for a single facility.⁴

Natural gas storage facilities cannot be viewed as self-contained operations but as nodes of the California, and in a broader sense of the North American, natural gas network. Injection and withdrawal decisions cannot be taken without accounting for the operational status of interconnecting pipelines which are, in turn, connected to the backbone pipelines owned by distribution utilities and ultimately to interstate pipelines. California receives its gas from Canada, the Rocky Mountains, and the Southwest producing basin.⁵ Once the gas is inside the state, it is either delivered by the interstate pipelines or distribution utilities to their respective customers, or stored.

Figure 1 displays the location of the main intrastate pipeline and storage infrastructure in California (California Energy Commission, 2002). SoCalGas and PG&E more or less divide California south and north, and operate with minimal interconnection of their backbone networks, even though in several places their pipelines are merely a few miles apart.⁶ These utilities' operations are subject to regulatory requirements, also with no coordination. Each utility must accumulate a given level of stocks by the beginning of the official withdrawal season to ensure they will be able to satisfy heating demand. PG&E and SoCalGas compute an annual rate base that they are entitled to recover according to rate-of-return style regulation. In contrast, Wild Goose and Lodi

³ Unlike for liquids like gasoline, pipeline or storage capacity for natural gas can be increased with additional compression. The concept of "capacity" acknowledges, however, the rapidly increasing costs beyond some levels of usage.

⁴ Systemwide, the constraints on transportation capacity may have profound affects on grain storage (Brennan, Williams, and Wright1997).

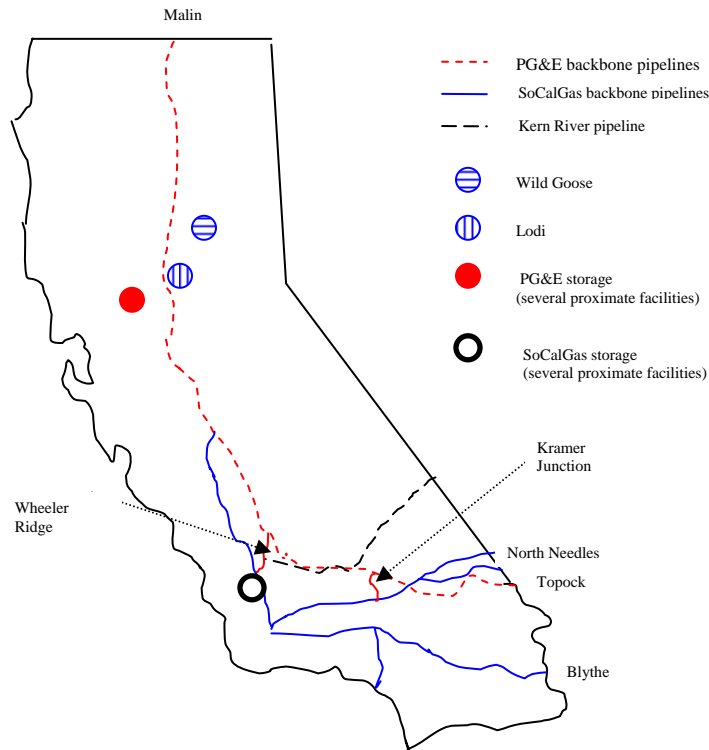
⁵ In-state production contributes about 15% of total consumption.

⁶ That is, various routes into California do not compete directly, unlike the situation De Vany and Walls (1996) have found for parts of the network in the Eastern U.S.

mainly store for others while also participating in some short-term trading on their own account.⁷ They charge market-based rates and are not protected from possible losses if total revenue in a given year turns out to be less than total costs.

Figure 1

Physical configuration of the California natural gas network



Storage facilities in Figure 1 and for the rest of the analysis are aggregated into four points, even though the two utilities each have several facilities in their two general areas marked in Figure 1. As the utilities provide aggregate data, that is the unit of analysis used here. Most of the capacity in utility-owned facilities is dedicated to “core”

⁷ Wild Goose gets its name from the prestigious hunting club below which a depleted gas field existed. Locating a storage facility there involved extra cost and inconvenience (the compressors had to be muffled for the sake of the ducks), but was anyway the best option because of the scarcity of locations with similar geological features and close to the PG&E backbone pipeline system.

customers, although industrial users and electricity generators can also acquire storage space in them.⁸ Alternatively, Wild Goose and Lodi also offer storage services to these noncore customers. Moreover, these independent facilities are demanding from regulators the right to serve utilities' core customers.

Table 1
Aggregate natural gas storage capacity in California⁹

Working gas capacity (Bcf) ¹⁰	Maximum injection rate (MMcfd)	Maximum withdrawal rate (MMcfd)
256	2,025	5,714

Given the amount of storage capacity available statewide, it would take 127 days, approximately four months, at the maximum injection rate to fill all of it. In practice, the injection season has to be longer (seven months officially) because there is not enough pipeline capacity available to bring all that gas into the storage facilities in a 4-month frame while satisfying the other daily demand requirements.

One of the basic trade-offs in designing energy distribution networks is that between pipeline and storage capacity. In the producing areas, nature herself provides storage facilities. In the extreme, no storage capacity in consuming regions would be needed if pipelines were built big enough to satisfy peak demand requirements. Because

⁸ Core customers are residential and small commercial customers who require utility gas service. Noncore customers are large customers who have alternative fuel capability, such as large commercial, industrial, cogeneration, wholesale and utility electric generation customers.

⁹ The capacity figures in Table 1 include the recent expansion undertaken at Wild Goose, which came online in April 2004 and added 10 Bcf of working gas storage capacity, 370 MMcfd of injection capacity and 280 MMcfd of withdrawal capacity. Nationwide storage capacity is some 9,000 Bcf.

¹⁰ 1 Bcf = 1,000 Mmcf. Natural gas flows are normally expressed in million cubic feet per day (Mmcf/d). On the other hand, the convention for prices is to use dollars per million British thermal units (\$/MMBtu). 1 MMBtu is approximately equal to 1 MMcfd. MMcfd is a measure of volume while MMBtu refers to the heating power (amount of energy required to raise the temperature of one pound of water one degree Fahrenheit).

such a configuration is clearly cost inefficient (huge pipelines would be half empty most of the year), storage comes into play. The flexibility with which storage facilities can be operated largely depends on the balance between working gas capacity and rates of injection and withdrawal. Low injection rate or a tiny pipeline interconnection diminish the usefulness of a storage reservoir as it would not be feasible to cycle its contents in one year, the relevant storage cycle imposed by natural gas demand.

Over the last two decades, deregulation and introduction of a futures market for natural gas changed the character of natural gas storage operations (Doane and Spulber, 1994). Previously, storage services were bundled with transportation, as they were strictly tools for balancing pipeline flows and for smoothing seasonal price fluctuations derived from the demand cycle.¹¹ Independent storage facilities, one of the byproducts of the deregulation process in the natural gas industry, have largely contributed to the rise of more market-oriented uses of storage capacity. The following set of figures illustrates the difference in injection profiles between utility-owned and independent storage facilities in California, especially the facility at Lodi.

¹¹ Indeed, transportation expenses themselves were often bundled into a pan-seasonal, pan-territorial price of natural gas (Hubbard and Weiner, 1991).

Figure 2

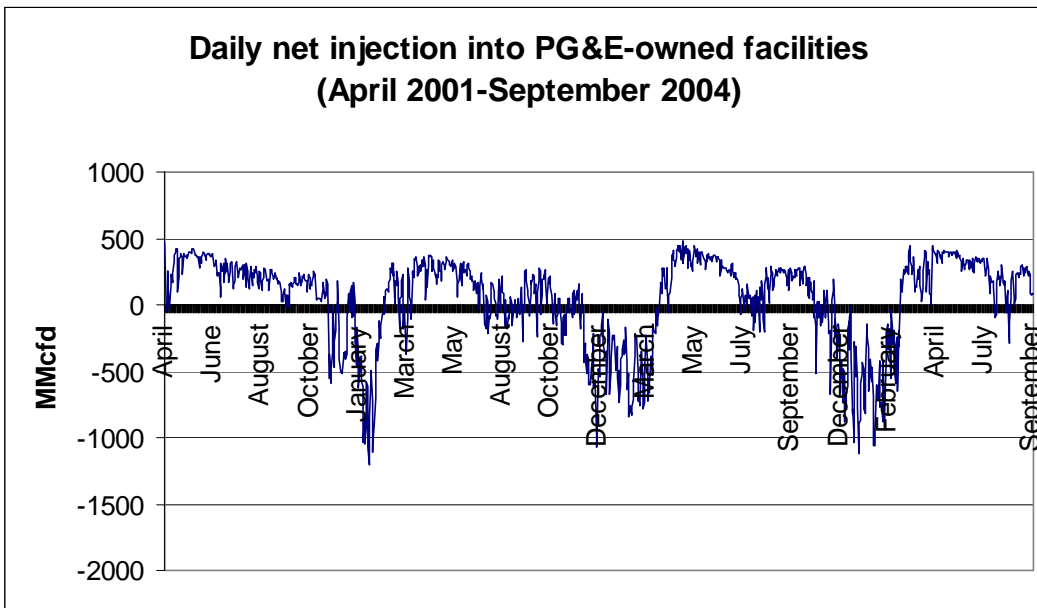


Figure 3

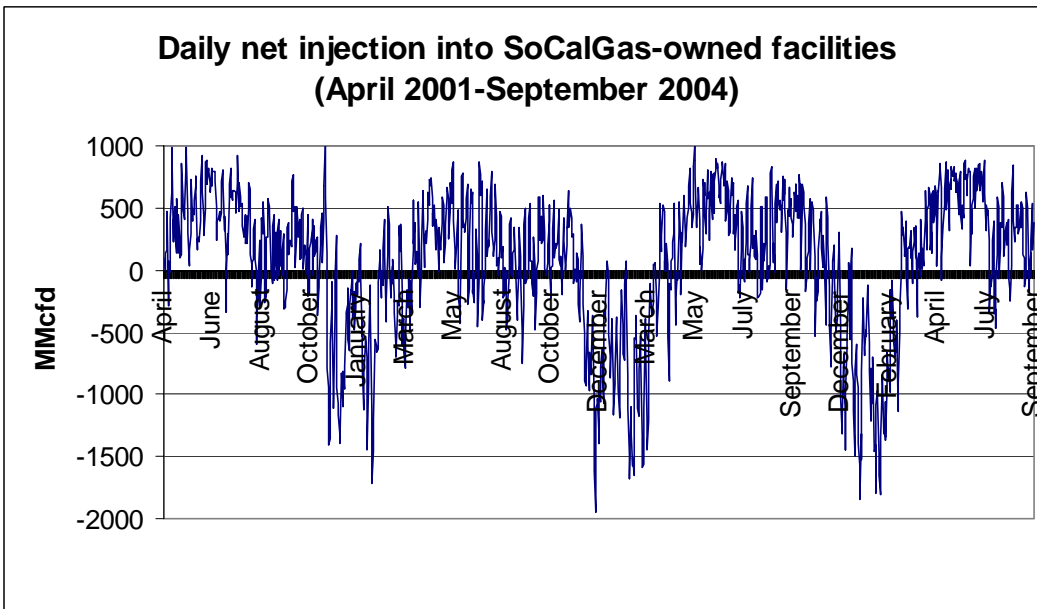
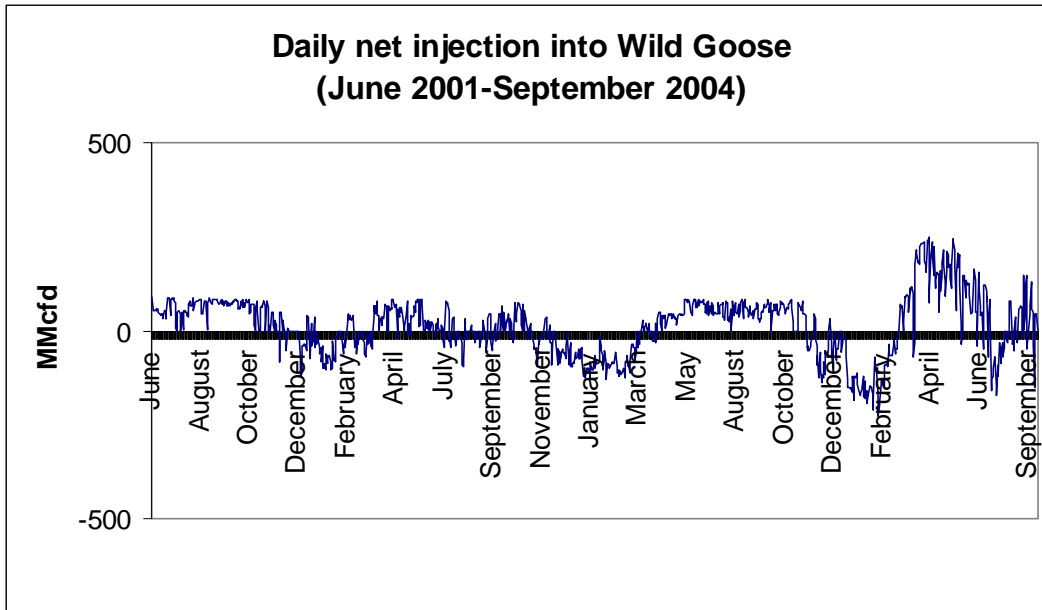
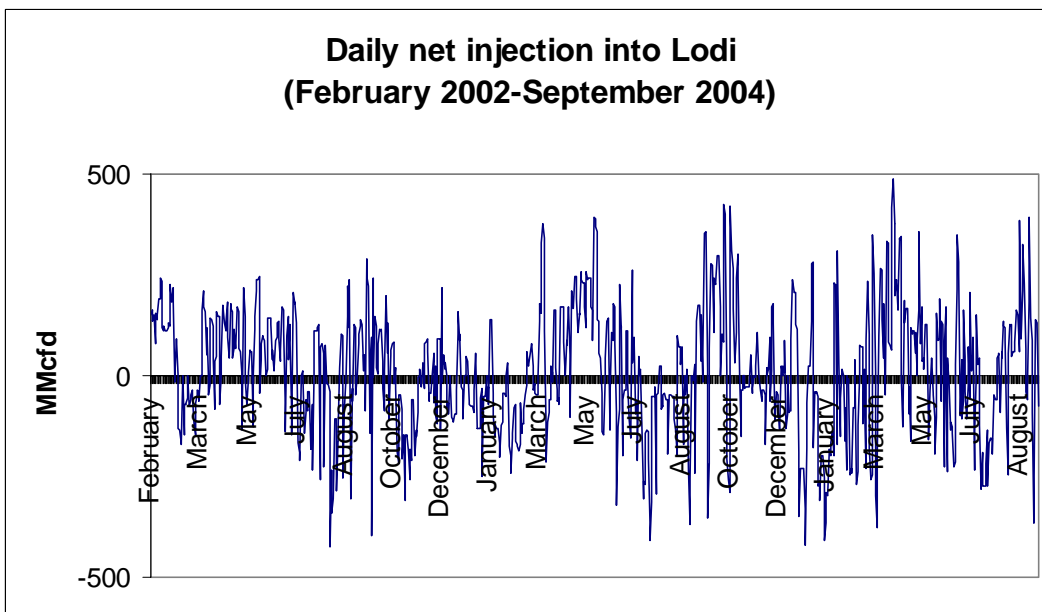


Figure 4



Note: Injection capacity at Wild Goose was upgraded from 80 to 450 Mmcf/d in March 2004

Figure 5



The series in Figures 2 and 3 for PG&E and SoCalGas follow a very similar seasonal profile in terms of flows into and out of storage. Such a strictly seasonal pattern is also discernible for Wild Goose in Figure 4, but not for Lodi, which switches continuously between injection and withdrawal. Although less frequently, the other three facilities also change the direction of net flows all through the year, so that the distinction between injection and withdrawal season is not completely clear cut. Figures 2 through 5 display enough variability to make the case for an econometric specification of injection decisions containing variables other than a seasonal dummy. Observations where gas is withdrawn during the official injection season and vice versa have the highest information content as to the relation between net injection and price spreads since chances are that switches to a countercyclical behavior are done in response to a price signal.¹² The percentage of countercyclical observations ranges from 12% for Wild Goose and 30% for Lodi.

Storage decisions are mainly being taken by three types of agents: utilities to satisfy core inventory requirements, industrial customers and electricity generators (these can choose between the storage services of the utilities or those offered by one of the two independent storage facilities), and independent facilities operating as proprietary traders. How much of their observed behavior can be explained with data on intertemporal and spatial arbitrage opportunities? The data set in this study does not contain information about individual customers, but it is disaggregated enough to provide insight into the storage behavior of the different groups.

¹² Conversations with the storage operators revealed that those switches are sometimes done for operational reasons like testing of the compressors.

3. INTERTEMPORAL SPREADS AND STORAGE DECISIONS IN CALIFORNIA

According to the theory of the “supply of storage” following from Working, stocks should be held when their value, as reflected in futures prices, is expected to increase enough over time as to cover storage costs. The bigger the contango, the more the commodity should be placed into storage. Figure 6 can be interpreted as California’s “supply-of-storage” curve for the April 2001- September 2004 period and emulates Working’s original plots for wheat. Stocks as of the first day of April, July, October, and January are plotted against the two-month spreads observed on those dates.¹³ The highest inventory buildups in California coincide with the deepest contangoes but approximately the same spread results for very different stock levels so the shape of the fitting curve suggested by the scatter plot does not follow closely the supply-of-storage theory. On the other hand, the positive relationship between stocks and spread (defined as the further-to-expiration minus the closer-to-expiration contract so that positive values are contangoes and negative ones backwardations) shows up clearly in Figure 7.¹⁴ The difference is that now stocks are plotted against the two-month spread observed two months before rather than the two month spreads observed on those dates. Comparison of Figures 6 and 7 suggests that, at this level of spatial aggregation, it is spreads that determine stocks rather than the other way around. The deepest backwardation (-0.743 \$/MMBtu in April 2001 with respect to the June contract) resulted in the lowest stock level two months later, although the biggest contango (\$0.644 in November 2003 with respect to the January 2004 contract) did not provide enough of an incentive to fill the storage capacity because

¹³ The spot price level at Malin on the Oregon border during this period has averaged at 4.11 \$/MMBtu but went as low as 1.22 \$/MMBtu and as high as 11.46 \$/MMBtu. Nearby futures prices were nearly as variable, around a slightly lower mean.

¹⁴ Over those three years, interest rates were stable and unusually low, so the spreads are not adjusted for financing costs.

it happened at a time of year in which demand for heating dictates the need for stock withdrawals.¹⁵ All in all, California stocks in the aggregate seem to be somewhat sensitive to the NYMEX intertemporal price signal.

Figure 6

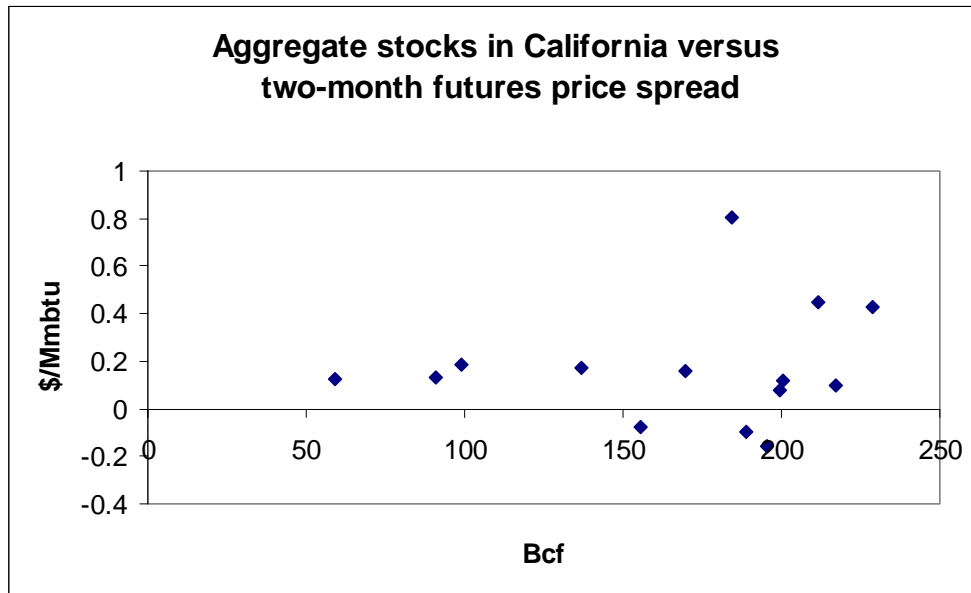
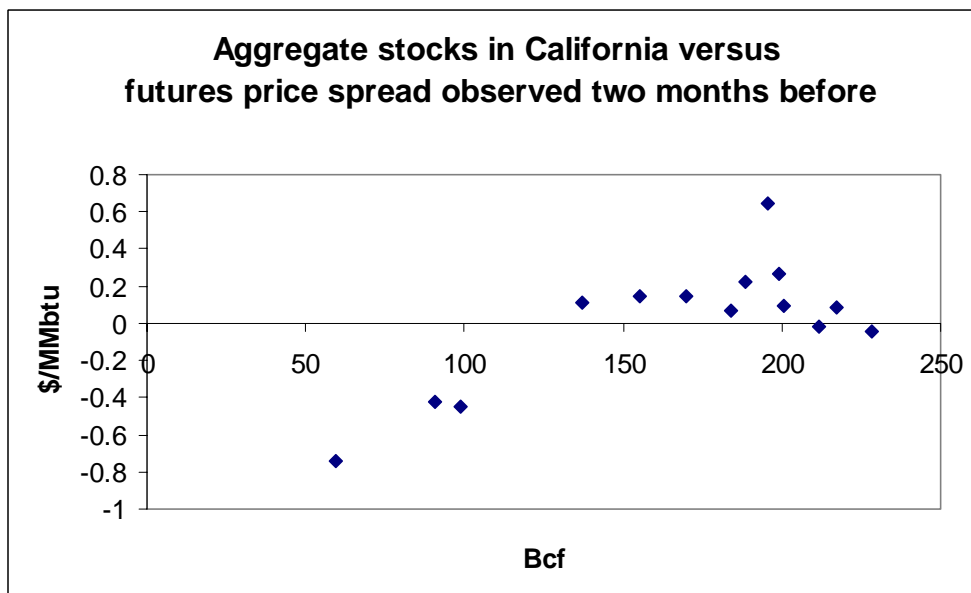


Figure 7



¹⁵ In percentage terms, contangoes for natural gas are sometimes much larger than for most other commodities.

Figure 7 shows the relationship for one particular length of spread. More generally, April 1 stocks reflect to some degree the whole history of spreads relative to the April futures contract. However, flows - injection or withdrawal - in April 1 should be responding to the array of price spreads observed that day. Past literature has focused on highly aggregated stock data and has not paid much attention to the determinants of flow decisions. What would be the information gains from using daily injection data over the traditional analysis of monthly stocks versus spreads? The following example illustrates the loss of information entailed when aggregating injection data. For instance, the daily average injection in PG&E-owned facilities in November 2001 was -4.81 MMcfd and all the price spreads considered were in contango at that time. However, daily data shows that injections took place for the first three weeks of that month (as it would be expected in response to a contango) and were followed by heavy injection in the last week of the month, withdrawals that offset almost entirely the initial injection. Also, the percentage of countercyclical observations in the weekly or monthly series is much smaller than in the daily ones, with those observations being the most helpful in teasing out the effect of price spread variability. Thus, the level of temporal disaggregation matters when it comes to capturing these relationships. The need for highly disaggregated data to carry out meaningful analysis of flows might explain why most of the literature on this topic restricts itself to data about stocks.

Figures 8 through 11 plot daily net injection versus the spread per month observed each day with respect to the futures contract for the beginning of the next season (either April or November).¹⁶

¹⁶ Daily data for stocks and net injection were provided by the California Energy Commission. Daily spot price data come from Natural Gas Intelligence, a reporting service that conducts daily surveys of

Figure 8

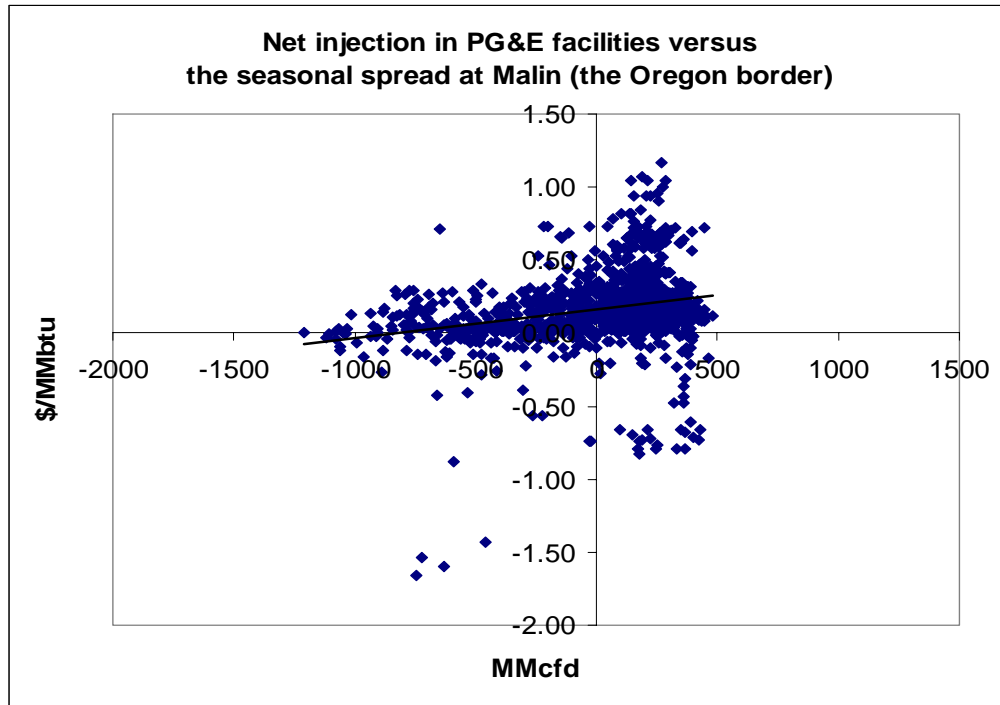
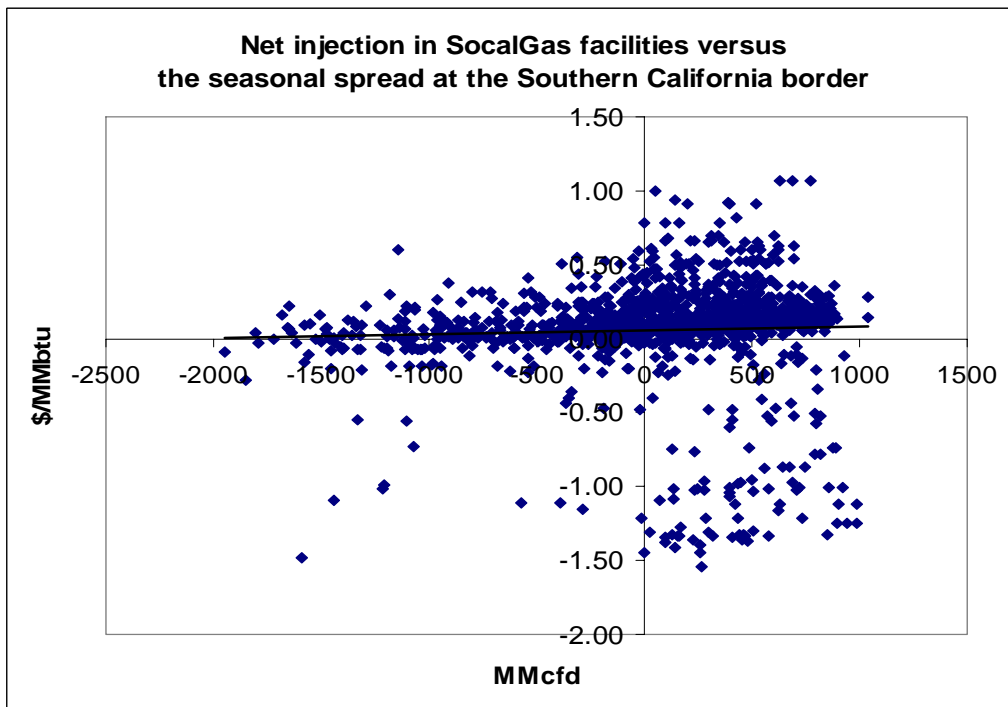


Figure 9



transactions at trading hubs across North America. Finally, the futures price data comes from Norman Consulting by way of NYMEX.

Figure 10

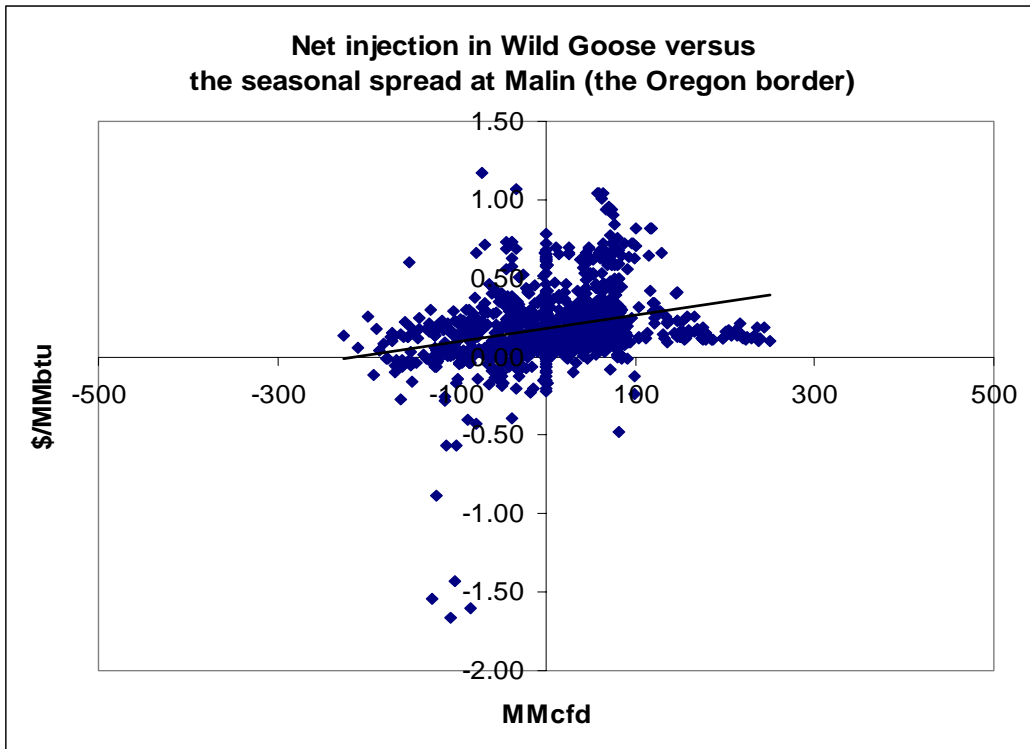
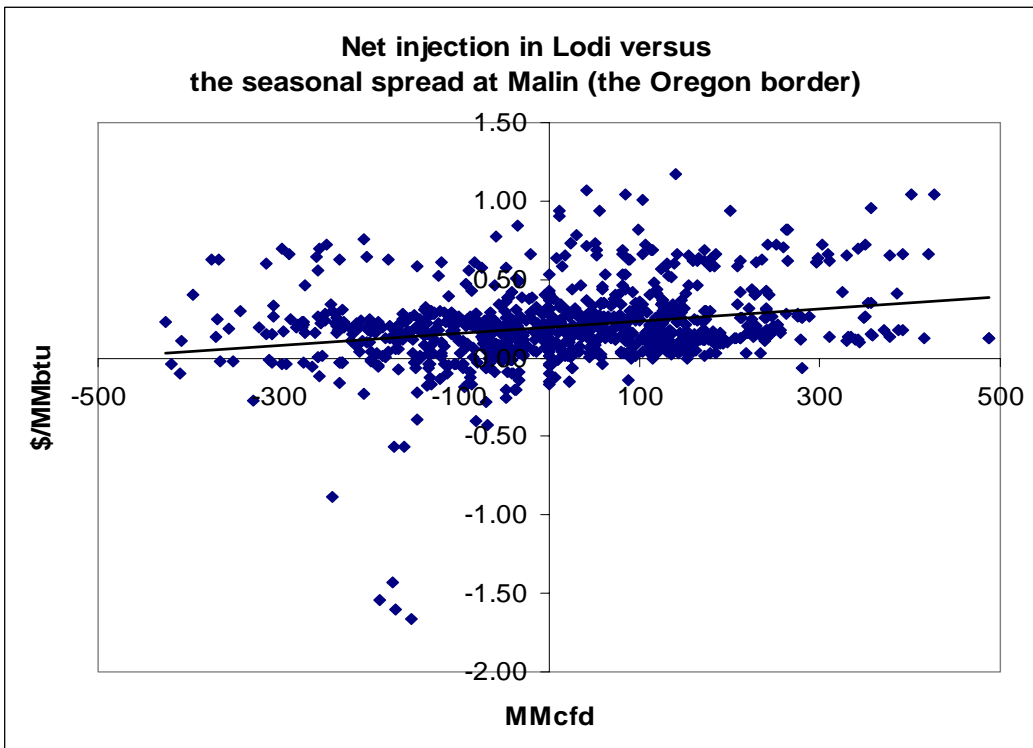


Figure 11



The positive relationship between the futures-spot differential and net injection is not very strong, for any of the four facilities. The intercept for each trendline provides, if the “supply of storage” theory is right, a rough estimate of the monthly carrying charge at that facility. All intercepts, except for the one in Figure 9 corresponding to SoCalGas, are in the range of 15-20 cents/ MMBtu. Only for a contango of at least that level would it be sensible to inject gas and hold it for a month. Figures 8 and 9 for PG&E and SoCalGas contain data that span the longer period starting in April 2001 (data for Wild Goose start on May 22 of that year and Lodi only started operation in January 2002). Points in the Southeast quadrant violate the “supply of storage” theory, even though Figure 7 above agrees with it for California aggregate stocks and two-month spreads.¹⁷ Those points mainly correspond to the first two months of the data set in which the local spot prices in California were at historical maxima for a host of reasons resulting in the California “energy crisis”. Because the stocks owned by PG&E and SoCalGas at that point were well below the historical average and it was the start of the official injection season, these facilities were switched into injection mode even though the local spreads were in deep backwardation. The utilities were not listening to the intertemporal price signal from the futures market.

Scatter plots look different across seasons, except at Lodi. The trendlines for the other three facilities are basically flat during the injection season and upward sloping during the winter months. Both PG&E and SoCalGas impose more rigid injection than withdrawal schedules to their customers. Existence of a regulatory requirement as to the

¹⁷ Clusters of points at the far right end of the quantity axis suggest that injection capacity is, at times, a binding constraint in PG&E, SoCalGas, and Wild Goose (for Wild Goose the constraint was relieved after its recent expansion). Withdrawal capacity does not seem to be binding.

minimum level of stocks hold by the utilities at the end of the injection season but not at the end of the withdrawal season are the ultimate reason for this asymmetry.

4. LOCATION SPECIFIC INTERTEMPORAL SPREADS

Because the natural gas futures market comprises 72 delivery months at any one time, there are as many simultaneous intertemporal signals. Which signal, if any, seems to be most relevant for flows and stock decisions in California? How much does the choice of spreads considered matter? And maybe a more profound question is: Should it matter?

Price spreads of a given length are constructed by subtracting a relevant spot price from a futures price. The chosen spot prices were Malin at the California-Oregon border, the SoCal border average, and the Henry Hub (the delivery location of the NYMEX futures contract).¹⁸ Spreads constructed using local spot prices combine an intertemporal and a spatial element. The former should reflect the pure carrying charge; the latter (e.g., difference between spot price at Henry Hub and at the California border) contains information about the cost of transporting natural gas to some point in California. The spatial spread, which is a “basis”, depends on how congested the pipelines are and on the contemporaneous relative value of gas in California versus Louisiana.¹⁹ The temporal and spatial elements can be separated by using the intertemporal spreads at the Henry Hub and the spot price differential between the California border and the Henry Hub.

¹⁸ The daily spot price at a given location is the average price from a survey of transactions involving gas to flow the next day. Most natural gas, however, is traded during the last five business days of each month (bidweek) to flow the following month. The average price from those monthly trades is the bidweek price.

¹⁹ The estimated coefficients from simple OLS regressions of spot prices at Malin and the Southern California border on NYMEX futures prices are 0.94 and 0.91 respectively. The intercept from those regressions (which can be interpreted as a locational basis) is 0.62 for the SoCalborder regression but not significantly different from zero for Malin.

Another choice in constructing the price spreads is what futures maturities to consider. Given that there are two official storage seasons, it makes sense to look at the futures contracts associated with their start (April and November). The “seasonal” spread defined here is, for any day, the difference between the spot price and the closer to expiration of the April and November futures contracts. The “seasonal” spread is then adjusted by dividing it by the number of months until expiration so that it refers to a price per month. The other spreads chosen are with respect to the nearby futures contract and to the third to nearest and sixth to nearest futures contract. They are all adjusted to represent the spread per month. Intuitively, at any one date, the spread per month associated with different futures contracts should be approximately the same; otherwise there would be arbitrage opportunities not being exploited. However, observation of the time series of the spreads revealed significant differences. For the season-long spread, the monthly spread escalates as the April or November contract expiration date nears. For the three-month spread, the monthly spread is higher October through December since the 3-month spread at that time of the year correspond to the January through March contracts, which reflect peak demand and generally reach the highest prices. For local spreads, the discrepancy across spreads per month follows also from differences in the locational basis throughout the year.

Table 2**Descriptive statistics of price spreads**

Spread (per month) \$/MMBtu	mean	standard deviation	minimum	maximum
Nearby futures- Malin spot	0.35	0.86	-6.08	1.92
3 month futures- Malin spot	0.15	0.93	-1.99	0.67
6 month futures- Malin spot	0.09	1.04	-0.99	0.45
Season-long futures- Malin spot	0.17	0.26	-1.66	1.17
Nearby futures- SoCal border spot	-0.17	1.89	-10.35	1.52
3 month futures- SoCal border spot	-0.02	1.92	-3.42	0.63
6 month futures- SoCal border spot	0.00	1.92	-1.71	0.37
Season-long futures- SoCal border spot	0.06	0.36	-1.54	1.07
Nearby futures- Henry Hub spot	0.06	0.37	-9.27	1.14
3 month futures- Henry Hub spot	0.06	0.62	-4.33	0.62
6 month futures- Henry Hub spot	0.04	0.78	-2.23	0.35
Season-long futures- Henry Hub spot	0.04	0.26	-6.13	0.88

Mean spreads constructed using either Malin or Henry Hub prices are in contango. As extreme as are some contangoes observed during these three years, even more extreme are the backwardations. The one for the California spreads of -10.35 \$/MMBtu corresponds to the very beginning of the data set. For the Henry Hub spreads, the price spike corresponds to February 25, 2003 coinciding with a cold spell in the East Coast. The asymmetry in the distribution of prices has its flip side in the observation made for Figures 5 through 7 (Bresnahan and Spiller, 1986): Injection capacity is used at its maximum (stopping the contango from deepening too much) but withdrawal capacity is not used similarly to limit the extent of backwardation with respect to the local spot price. Why is withdrawal capacity not used more heavily in response to backwardations

(or in response to contangoes that do not cover the full carrying charge)? Bottlenecks in pipelines and regulatory inventory requirements are plausible explanations. Data about daily flows in and out of storage allow for deeper investigation of these issues.

Even though price spreads of different lengths often evolve in near parallel (the correlation coefficients among the four futures contracts used in this analysis in the 2001-2004 period range between 0.89 for the nearby-6-month pair and 0.96 for the season-long-3-month pair), this similarity does not mean that all of them will be equally significant in explaining injection and withdrawal decisions. Different storage customers will consider different spreads to be relevant. For instance, utilities should be especially interested in the “seasonal” spread given their service obligations toward core customers in the winter. Do their injection decisions April through November take into consideration nearby spreads as well? This is one of the questions that will be addressed in the following section.

5. SENSITIVITY TO SPREADS

Literature on the “supply of storage” looks at the relationship between stock levels and spreads. Typically, price spreads have been considered the dependent variable and explained by the stock level. This direction of causality is merely a convention established in Working’s seminal studies; at the aggregate level, both stocks and spreads are simultaneously determined. However, as data are disaggregated over time or space, one direction of causality may stick out as more sensible than the other. Information about the NYMEX futures is available daily and may inform day-to-day decisions on how much gas to put into storage. The Energy Information Administration (EIA)

releases U.S. inventory reports on a weekly basis, which Linn and Zhu (2004) have shown have an effect on NYMEX futures prices. On a daily basis, inventory changes are likely to play not much of a role in determining futures price spreads just because the information is not easily available at that frequency.

On top of the decisions as to the direction of causality, the econometric analysis of injection and spread data series pose issues related to the time series nature of the data. The injection/withdrawal series is simply the first difference of the stocks series (which, especially at the daily level, has a unit root). Stocks at one moment are a function of prices at that moment but also of the history of prices from the beginning of the injection season. Net injection in any one day, however, would ideally only depend on the prices observed in that one day: The history of net injections is indirectly accounted for in the stock level itself. In practice, operational and regulatory restrictions can hamper immediate transmission of price changes to storage decisions. As an example, SoCalGas requires their storage customers to give two-day notice as for the gas they want to inject or withdraw. Therefore, the second lag of the spreads rather than the contemporaneous spread was used for the regressions corresponding to the facilities owned by this utility. Natural gas flows in and out of storage continuously while prices are only generated during business days. According to industry convention, the price that applies to storage flows during weekends and holidays is that from the last business day. Such assumption allows equalizing the length of the stock and price series but also alters the structure of the latter. Both daily injection and daily spreads are highly autocorrelated. For the spread series, the hypothesis of a unit root can be rejected at the 1% level in all cases (such result is robust to the assumption made about non-business days). The stock level

series present strong evidence of the existence of unit roots. The correlograms of the net injection series show strong first order autocorrelation but the null hypothesis of a unit root can be rejected at the 5% significance level. Including the lagged dependent variable as a regressor corrected for autocorrelated errors and weakened the significance of the spread variables.

List of variables

Dependent variable: Net injection (MMcfd)

Regressors:

lagged injection- first lag of net injection series (MMcfd).

stock – daily stock level (Bcf).

official season – 1 if April through October, 0 otherwise.

business day- 1 if business day, 0 otherwise.

day-of-week dummies (the results from the six dummy variables must be interpreted with respect to Sunday, which is the one left out).

spread- NYMEX futures closing price for the seasonal or nearby contracts (\$/MMBtu)- Malin (SoCal border) daily spot price.

crisis- 1 for the first 25 observations in PG&E and the 72 first observations in SoCalGas (the break points were assessed through a Chow test).²⁰

Henry Hub spread- NYMEX futures closing price for the seasonal or nearby contracts (\$/MMBtu)- Henry Hub spot price

basis- Malin (SoCal border) daily spot price – Henry Hub spot price.

All the regressions were run for four different spreads (seasonal, nearby, 3 months to maturity and 6 months to maturity). Results are only reported for the first two but references to the other will be made when they offer extra insight.

²⁰ The crisis dummy is not included in the regressions corresponding to the independent facilities because the data available for them is posterior to the period of extreme backwardation.

Table 3

Estimated coefficients from OLS regressions of net injection on local spreads

	PG&E		SoCalGas ²¹		Wild Goose ²²		Lodi	
	seasonal	nearby	seasonal	nearby	seasonal	nearby	seasonal	nearby
R ²	0.876	0.876	0.860	0.860	0.847	0.847	0.544	0.547
D-W statistic	2.05	2.05	1.89	1.89	2.10	2.10	2.13	2.13
lagged injection	0.865 (45.72) ²³	0.868 (46.21)	0.845 (48.39)	0.846 (48.33)	0.841 (43.04)	0.841 (41.16)	0.629 (21.31)	0.623 (21.60)
stock	-0.582 (-2.779)	-0.692 (-3.064)	-0.523 (-1.86)	-0.495 (-1.781)	-0.422 (-1.659)	-0.434 (-1.688)	-5.531 (-4.870)	-7.725 (-6.019)
official season	62.142 (5.903)	65.644 (6.113)	117.67 (6.386)	119.72 (6.555)	14.501 (5.389)	14.943 (5.531)	28.383 (3.556)	35.584 (4.548)
business day	-14.369 (-0.639)	-16.929 (-0.780)	-111.18 (-2.534)	-110.64 (-2.527)	-2.305 (-0.452)	-2.586 (-0.499)	-59.551 (-2.767)	-51.737 (-2.528)
Monday	-24.094 (-1.043)	-23.566 (-1.047)	-263.70 (-5.827)	-264.25 (-5.854)	2.051 (0.406)	2.045 (0.400)	39.383 (1.830)	34.263 (1.672)
Tuesday	30.979 (1.222)	31.156 (1.256)	97.730 (1.995)	97.787 (1.999)	-11.200 (-1.948)	-11.307 (-1.959)	-38.986 (-1.631)	-44.855 (-1.958)
Wednesday	39.041 (1.599)	39.878 (1.673)	58.517 (1.188)	56.981 (1.155)	1.668 (0.297)	1.665 (0.293)	4.631 (0.189)	-2.185 (0.092)
Thursday	31.369 (1.237)	32.420 (1.311)	110.19 (2.295)	108.09 (2.243)	4.321 (0.705)	4.349 (0.703)	27.791 (1.209)	21.504 (0.981)
Friday	52.945 (2.150)	55.615 (2.330)	179.02 (3.642)	177.14 (3.580)	2.332 (0.444)	2.605 (0.489)	30.416 (1.272)	22.517 (0.973)
Saturday	65.828 (5.913)	65.911 (5.952)	151.12 (7.365)	149.85 (7.282)	8.788 (3.321)	8.781 (3.322)	62.510 (5.502)	61.685 (5.297)
seasonal spread	33.173 (2.202)		29.830 (1.053)		3.621 (0.888)		47.608 (2.894)	
nearby spread		-15.106 (-1.419)		1.88 (0.226)		-2.433 (-1.227)		44.038 (4.448)
crisis	-7.546 (-0.272)	-23.112 (-0.812)	-39.038 (-1.067)	-19.016 (-0.326)				
constant	-9.775 (-0.552)	9.373 (0.455)	-0.833 (-0.0314)	-0.567 (-0.021)	-3.189 (-0.991)	-1.648 (0.494)	46.196 (4.542)	45.388 (4.420)

The seasonal, local spread is significant for PG&E and Lodi. For SoCalGas, the six-month spread is the only one significant across the four considered. The fact that Lodi appears by far as the most price sensitive facility can be attributed to a combination

²¹ The spreads for the SoCalGas regressions are lagged twice to represent the two-day notice rule that SoCalGas imposes on their customers.

²² Results for Wild Goose refer to the pre-expansion period.

²³ t statistic in parenthesis. Estimated coefficients whose t statistic is above 1.660 are significant at the 5% level and bolded.

of reasons. First, the time period for which data for this facility are available is shorter as it started operating in 2002. Second, the geological characteristics of this reservoir provide more turnaround capability (i.e., it is easier to switch between injection and withdrawal) than at any other facility in California. Third, there could be behavioral differences on the side of the customers (more on the speculative side of the spectrum of holders of natural gas stocks) or of the facility owners by offering shorter-term, more flexible contracts.

For Wild Goose, the apparent insensitivity to spreads can be a result of the model specification. Injection capacity was often binding at Wild Goose before the upgrade that came online in April 2004 effectively truncating the relationship between flows into storage and contangoes. When only the post-expansion period is considered, both the nearby and three-month spreads are significant but five months of data are not enough to be confident on that result, which is why only the pre-expansion period is considered for the regression analysis. Price spreads continued to be insignificant in a tobit specification accounting for truncation of the net injection distribution due to capacity constraints. Insensitivity to price signals does not carry on to a regression of weekly average injection on weekly average spread, which indicates some degree of reaction to the evolution of price spreads during the weekly cycle.

The results in Table 3 correspond to regressions in which contemporaneous spreads are used to explain injection decisions. However, it could be that the response to price signals happens with a lag due, for instance, to operational constraints. Conclusions for either of the facilities in Northern California do not change when using the first and

second lags of spreads either in addition or as a substitute for the contemporaneous spread.

Another factor that can be muffling the response of injection decisions to changes in price spreads is the use of storage in the pipelines themselves (line packing) as a short-term, cheaper substitute for storage in underground facilities. In the PG&E system, pipeline inventory can range between 3,900 and 4,500 MMcf so there is a 600 MMcf buffer that can be used to accommodate daily supply/demand imbalances and to “park” gas for a few days. The “line pack” displays a clear weekly cycle with inventory buildup during the weekend and reductions during the week. Weak, negative correlation between weekly pipeline inventory change and weekly net injection confirms a degree of substitutability between both. The correlation between line pack and either price spreads or spot prices is very low as well, suggesting line pack’s main role is as an operational buffer for daily supply-demand imbalances.

In all regressions in Table 3 except for one, there is a negative and significant relationship between the current stock level and the day’s net injection. This variable gets at the nonlinearity in injection costs; when the storage reservoir is nearly full, additional injections become increasingly costly in terms of needed compression power.

As for the seasonal dummy, the econometric results confirm what Figures 2 and 3 show graphically: All facilities except for Lodi follow a clear seasonal cycle with higher injection April through October. The six-month spreads become significant at both PG&E and Wild Goose when interaction effects between season and spread are incorporated into the regressions.

Apart from the seasonal cycle, all facilities reveal a similar weekly cycle with injection peaking Friday and Saturday and reaching a low Monday in the utility-owned facilities and on Tuesday in the independent facilities. Storage activity is generally lower (a significant estimated coefficient for SoCalGas and Lodi) during business days in which gas is being traded.²⁴ Competition for pipeline space between gas for storage and gas for consumption is a likely explanation for this result as demand for consumption (especially, industrial and electricity generation demand) is higher on business days. Consequently, the operators of storage facilities should care about the current spot price for their inflow and outflow decisions for two reasons. First, the spot price influences the price spread which reveals the expected change in the value of stocks in a given period (value effect). According to the value effect, as the spot price goes up relative to the futures price, stocks should be withdrawn. This would be the only effect according to traditional supply-of-storage formulations. Second, because gas moves through a fixed capacity pipeline network, the links between local spot price, demand and pipeline load factor determine the amount of space available in the pipelines (congestion effect).²⁵ The sign of this effect on storage injections is not obvious a priori. Value and congestion effects will in some instances offset each other and when only one of them is accounted for (the regressions in Table 3 only consider the value effect), results can go against the postulates of “supply of storage” theory.

One way of ascertaining the effect of contemporaneous competing demands on injection decisions would be by using temperature, because temperature constitutes one

²⁴ Often, customers of the independent facilities make deals on Friday for gas flows in Saturday, Sunday and Monday. That may explain why Tuesday behaves as the beginning of the business week for Wild Goose and Lodi.

²⁵ Load factor= (pipeline flow/ pipeline working gas capacity)*100.

of the main drivers of natural gas demand.²⁶ Daily average temperature data for the period of interest are only available for the PG&E system. The relationship between temperature and net injection in the facilities located in California is best represented through a positive linear and a negative squared term and renders the local spread variables insignificant at both PG&E and Wild Goose. System demand or system load factor cannot be brought as right hand side variables in the regressions but scatter plots reveal a negative relationship between daily net injection and system demand and a positive one with respect to the system load factor

Table 4: Correlation coefficients between net injection and demand or system load factor

	PG&E	SoCalGas	Wild Goose	Lodi
System utilization factor	0.26	0.59	0.23	0.34
Demand	-0.73	0.03	-0.59	-0.33

Two additional pieces of information relevant to the relationship between all these variables are the correlation coefficients between system utilization factor and demand in the PG&E (0.31) and SoCalGas systems respectively (0.23). These low coefficients indicate that peak demand days do not correspond necessarily with peak utilization of pipeline capacity (which is directly related with amount of supplies brought from outside the state). Flows in and out of storage make it possible to break this link. Withdrawals from storage facilities complement out-of-state supplies when gas consumption

²⁶ Regressions identical to the ones referred to in Table 3 but including the spot price as a regressor provide mixed evidence across facilities. Only for PG&E is the spot price clearly significant and, by including it in the specification, the seasonal and 6-month spread variables become positive and significant for this facility as well.

requirements are high, hence the negative correlation coefficients between demand and net injections in the PG&E system. The sign, but not the magnitude, of the correlation with the system load factor is somewhat trivial as flows going into storage are part of the total flow coming into the state.

The evidence for storage decisions in California being made with an eye on profitable arbitrage opportunities is weak according to the regressions in Table 3. Because such behavior is hard to believe in the context of a well integrated natural gas network at the national level and of a highly liquid natural gas futures market, alternative specifications must be investigated. One possibility could be that storage operators and their customers looked at the pure intertemporal price spread implied in the array of NYMEX futures prices and at the locational basis separately. NYMEX offers basis swap futures contracts at Malin and SoCal that provide protection from basis risk and allow taking advantage of spatial arbitrage opportunities. For instance, when a cold spell in the Eastern U.S. causes spikes in prices in that region, those in California holding inventory and with a long position in the basis contract would choose not to take delivery of the commodity but sell it and use up their stocks. The set of regression results in Table 4 correspond to a specification in which the intertemporal spreads at Henry Hub and the spread between the local and Henry Hub spot prices are considered instead of the local spreads. Separating the temporal and spatial price differentials is a way of getting at the two effects (“value” and “congestion”) mentioned before, assuming that higher value of gas at the California border relative to Henry Hub translates in high load factors in the pipelines bringing gas to California (i.e., assuming gas tend to flow where it is most

valued). The correlation coefficients between system utilization factor and locational basis are 0.34 and 0.36 for the PG&E and SoCalGas systems respectively.

Table 5

Estimated coefficients from OLS regressions of net injections on Henry Hub spreads and locational basis.

	PG&E		SoCalGas		Wild Goose ²⁷		Lodi	
	seasonal	nearby	seasonal	nearby	seasonal	nearby	seasonal	nearby
R ²	0.878	0.877	0.861	0.861	0.848	0.847	0.548	0.547
D-W statistic	2.05	2.05	1.88	1.89	2.08	2.08	2.13	2.13
lagged injection	0.849 (42.86)	0.860 (43.92)	0.838 (46.83)	0.844 (47.59)	0.819 (37.33)	0.829 (38.08)	0.618 (20.89)	0.621 (21.23)
stock	-0.891 (-3.969)	-0.801 (-3.693)	-0.593 (-2.100)	-0.543 (-1.946)	-0.367 (-1.369)	-0.361 (-1.346)	-6.616 (-5.701)	-7.807 (-5.994)
official season	60.213 (5.742)	66.779 (6.271)	114.54 (6.247)	121.72 (6.657)	14.296 (5.331)	14.926 (5.575)	19.792 (2.361)	35.846 (4.547)
business day	-12.600 (-0.565)	-11.322 (-0.500)	-109.56 (-2.508)	-108.88 (-2.480)	-1.068 (-0.214)	-1.245 (-0.247)	-54.222 (-2.599)	-51.486 (-2.509)
Monday	-26.311 (-1.145)	-26.838 (-1.154)	-264.99 (-5.881)	-265.77 (-5.865)	0.933 (0.188)	1.117 (0.224)	35.981 (1.718)	34.012 (1.657)
Tuesday	28.292 (1.124)	27.998 (1.097)	94.908 (1.941)	95.177 (1.940)	-12.391 (-2.203)	-12.265 (-2.165)	-42.766 (-1.835)	-45.048 (-1.962)
Wednesday	35.677 (1.467)	35.818 (1.453)	55.793 (1.135)	55.291 (1.119)	0.089 (0.016)	0.458 (0.082)	-0.434 (-0.018)	-2.735 (-0.116)
Thursday	27.697 (1.096)	28.219 (1.102)	107.80 (2.249)	106.84 (2.215)	2.802 (0.468)	3.218 (0.532)	22.164 (0.996)	20.904 (0.949)
Friday	49.244 (2.008)	49.805 (1.998)	176.16 (3.589)	175.64 (3.548)	0.800 (0.155)	0.213 (0.232)	23.470 (0.996)	21.954 (0.945)
Saturday	64.162 (5.782)	65.528 (5.879)	149.88 (7.283)	150.06 (7.290)	8.450 (3.242)	8.665 (3.330)	60.589 (5.306)	61.386 (5.272)
Henry Hub spread	67.188 (4.445)	28.039 (2.868)	66.717 (2.843)	23.073 (1.434)	8.003 (1.850)	2.417 (1.345)	75.568 (4.413)	47.297 (3.746)
locational basis	-7.441 (-3.252)	-5.511 (-2.420)	-7.271 (-1.014)	-3.151 (-0.431)	-2.430 (-2.928)	-2.110 (-2.558)	-46.805 (-4.452)	-42.387 (-4.135)
crisis	-47.310 (-1.616)	-40.403 (-1.380)	65.837 (1.155)	33.402 (0.573)				
constant	13.799 (0.750)	3.801 (0.212)	7.112 (0.262)	0.424 (0.016)	-5.452 (-1.461)	-5.647 (-1.519)	45.425 (4.354)	46.787 (4.404)

²⁷ Results for Wild Goose refer to the pre-expansion period.

The purely intertemporal seasonal price spread contributes to an explanation of net injection in all of California facilities. All injection decisions except for those at SoCalGas-owned facilities are made with an eye on spatial arbitrage opportunities as well. For facilities in Northern California, this result is robust to introduction of the temperature variable. PG&E follows more closely the Henry Hub spread than the evolution of the locational basis; for the independent facilities both the temporal and spatial dimensions have similar weight in deciding daily injection volumes.

Table 6

Estimated coefficients (as % of injection capacity) on Henry Hub spreads of different lengths

	season-long	nearby	3-month
PG&E	17.91 (4.445)	7.47 (2.868)	20.38 (4.233)
SoCalGas	8.34 (2.843)	2.88 (1.434)	10.45 (2.637)
Wild Goose	10.00 (1.850)	3.02 (1.345)	16.37 (2.177)
Lodi	18.89 (4.413)	11.82 (3.747)	34.60 (5.178)

Note: all price spreads have been adjusted to represent the spread per month

The coefficients are directly comparable across facilities, as they all have been expressed as percentage of total injection capacity, but not across spreads. The differences in magnitude of the effects of different spreads stem from the fact that the monthly spread varies across spread lengths. The same increase in spread in absolute terms represents different increases in relative terms for the various spread lengths. The utility serving Southern California is less tuned to price spreads than the utility in the northern part of the state even though both face inventory requirements by the end of the

injection season. The nearby spread is the least relevant across the board, probably as a result of it being also the most volatile.

CONCLUSIONS

No definitive statement can be made about the responsiveness of injection and withdrawal decisions to futures price spreads for the case of California natural gas. The aggregate “supply-of-storage” curve where stocks are plotted against the spreads that plausibly inform the flow decisions resulting in that level of inventories looks sensible. The aggregate pattern is dictated by the behavior of the biggest storage operators, namely, the two local distribution utilities. Neither of them seems to respond to the full array of local price spreads on a daily basis but do pay attention to the NYMEX futures price spreads. As for the small independent facilities, Wild Goose behaves as a seasonal storage facility while regression results for Lodi fit better the profile of a profit-making operation, trying to take advantage of short-lived arbitrage opportunities. In either a graphical or basic econometric analysis of the net injection-spread relationship for the particular case of natural gas in California, it is difficult to disentangle the effects of multiple rigidities stemming from a nonlinear cost structure in storage operations, scheduling processes in the context of a network and regulatory requirements. A closer examination of the determinants of switches between injection and withdrawal decisions observed in daily data, maybe by means of a threshold regression model, could be a useful extension. Finally, it would be interesting to compare the California case with some other area closer to the Henry Hub to see how much does distance mute the price signals implied by the NYMEX futures price spreads.

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